COM-RT-2

Before the Hawaii Public Utilities Commission

Rebuttal Testimony of
Jim Lazar, Consulting Economist

On Behalf of
County of Maui

Docket No. 03-0371

October 22, 2004

Exhibit COM-RT-2
Rebuttal Testimony of Jim Lazar
On Behalf Of
County of Maui

Q. Are you the same Jim Lazar who previously submitted direct testimony and exhibits on behalf of the County of Maui?

A. Yes.

Q. What is the purpose of your rebuttal evidence in this proceeding?

A. I respond to the testimony submitted by HECO and by the Consumer Advocate on several topics. These include:

- **Market Power** issues associated with utility involvement in CHP, where I demonstrate that HECO would have a very dominant market position under its proposal.
- **Lost Revenue** issues raised by HECO, which I find to be a smokescreen under current circumstances, where avoided marginal costs greatly exceeded embedded cost based tariff rates.
- **Standby Rate** issues, where I propose a form of rate design previously approved by the New York Public Service Commission that I believe constructively addresses the concerns about unbundling raised by the Consumer Advocate's witness, and will result in rates that are fair to the Companies and attractive to potential DG customers. I advocate that these types of standby rates be available on a non-discriminatory basis to all self-generation customers, whether they own their own facilities or buy CHP service from the utility (if that is allowed).
- **Time-of-Use** rate issues, where I respond to Ms. Seese's assertion that the current load factor block rates are a proxy for time-of-use rates, and I develop and propose

the substitution of TOU rates for the current load factor block rates.

Q. Are you sponsoring rebuttal exhibits with this testimony?

A. Yes. I am sponsoring the following exhibits:

COM-R-201	Market Power Index Calculation
COM-R-202	Lost Revenue Imputation
COM-R-203	Standby Rate Design Development
COM-R-204	Time Of Use Rates As Alternative to Load Factor Blocks

Q. Please begin with the market power issues. What is "market power" and how is it traditionally measured?

A. Market power exists when one supplier has a sufficient dominance of the market for any particular good or service that they can influence the price or characteristics of the marketplace. In the electric power area, market power was determined to be a primary cause of the west coast energy crisis of 2000-2001. A decline in power from hydro resources due to a drought created a situation where individual power plant owners could cause a market price increase by withholding supplies – and reportedly did so in order to increase their own profitability. By definition, if one supplier can affect the market price, a non-competitive situation is present.

Market power is often measured by what is known as the Herfindahl-Hirschman Index, or HHI, which turns market shares into a measure of market concentration.

Q. What are the market power issues raised by the CA and HECO testimony?

A. Both HECO and the CA recommend that the utility be allowed to offer CHP service as a

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regulated utility service. There is reason to believe that this would lead to HECO being in a dominant position, and able to exert market power. This is a principal reason that Mr. Kobayashi is recommending that the utility NOT be permitted to offer this service.

Q. What market share does HECO estimate it would have if its CHP proposal were accepted?

A. HECO estimates in Exhibit A to its CHP application that it would have the following market shares on each of the islands:

Island	HECO-Owned	Total Systems	HECO %
Oahu	72	97	74%
Hawaii	68	92	74%
Maui	76	99	77%

Q. How does one calculate the HHI from the data supplied by HECO?

A. The HHI is computed as the sum of the squares of the market share of each market participant. If one participant has 100% of the market, the HHI is 10,000, a completely concentrated market. If each of ten participants has 105 of the market, the index is ten times ten-squared, or 1,000.

Q. At what point does a market become unacceptably concentrated?

A. According to FERC[1] a market is "unconcentrated" if its HHI is less than 1,000, moderately concentrated if the HHI is between 1,000 and 1,800, and "highly concentrated" if

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[1] See: Williams and Rosen, A better Approach to Market Power Analysis, Tellus Institute, July 14, 1999, P. 3

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the HHI is above 1,800.

Q. What would the HHI be for each of the three islands if the estimates prepared by HECO were to occur?

A. In order to measure HHI, it is necessary to know the market share of each participant; HECO's analysis provides only their estimate for the market share that the utility would control. In computing the HHI, I have calculated a range, with the minimum HHI resulting from each non-HECO system having a separate vendor, and the maximum HHI resulting from all non-HECO systems having a single vendor. It does not really matter -- the share of the market that HECO expects to secure creates a highly concentrated market regardless of whether one or multiple vendors share the "crumbs" that are left over.

The HHIs for each of the three islands are shown below, and are calculated in COM-R-201. These are derived from the estimates prepared by HECO in Exhibit A of the CHP docket:

Hawaii CHP Herfindahl-Hirschman Indices If HECO CHP Estimates Achieved

Any Level Over 1800 is "Highly Concentrated"

System	Minimum HHI[2]	Maximum HHI[3]
HECO	5536	6174
HELCO	5491	6144
MECO	5917	6433

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[2] The "Minimum HHI" assumes that the utility owns the number of systems identified in Exhibit A, and each remaining system is owned by a separate vendor.

[3] The "Maximum HHI" assumes that the utility owns the number of systems identified in

Q. What conclusions do you draw from this analysis?

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Exhibit A, and all of the remaining systems are owned by a single competing vendor.

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Q. Have other Commissions considered the market power issue as it relates to utility ownership of distributed generation resources?

A. Yes. Mr. Kobayashi discusses dockets in Hawaii, New Mexico, and Louisiana in which the state Commissions have ruled that it is inappropriate for utilities to diversify into business areas that are not really "utility" service.

In New Mexico, the specific rulings in 1996 was really very similar to the situation postulated in this docket: the utility was informed that it could not offer "optional" non-traditional services either as a utility or as a non-utility subsidiary, due to market power and audit issues.[4]

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[4] See New Mexico Public Utility Commission Cases 2655 and 2688.

I have discussed these cases with the then-presiding Chairman of the New Mexico Commission (Mr. Wayne Shirley, one of my colleagues at the Regulatory Assistance Project), and he has confirmed to me that market power concerns were a key element in these decisions.

Lost Revenue

Q. What is the lost revenue issue raised by the CA and by HECO?

A. Both of these parties express concern that non-utility DG will result in lost utility revenues. They somehow jump to the conclusion that this would result in higher rates to non-DG customers.

Q. Do you agree with their analysis?

A. No, there is no analysis to support their testimony, only unexplained allegation. There are two issues. First, will customer-owned and third-party DG result in lost utility revenues. Unquestionably, yes. Second, will this result in higher rates to non-DG customers. Almost certainly not – in fact, the opposite is the likely outcome.

Q. Please begin with measuring the lost revenue issues associated with customer-owned DG systems.

A. Compared with utility service, the utility would lose the retail revenues paid by a customer. It would gain the standby revenues paid by the customer. The net of these two could be summed to measure the lost revenue. There is little doubt that this would be substantial. The example below suggests the magnitude of this for a customer with 500 kw of load that could be served with DG:

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MECO Retail Lost Margin from 500 kw Customer

Element	Unit Cost	500 kw @ 50% Load Factor
Retail Rate	$.1558/kwh	$341,202
Variable Cost (estimated)[5]	$.11/kwh	($240,900)
Contribution to Fixed Costs	$.0458/kwh = $16.71/month/kw	$100,302

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Q. Why would this not lead to higher rates for other customers?

A. Very simply because this calculation does not tell the whole story. A utility has both revenues and expenses. To measure only the lost revenues, but not the long-run avoided costs, is to look at the issue very deceptively.

First, the utility will avoid the need to invest in new generation, transmission, and distribution facilities. These avoided costs should be netted out from the "lost margin" calculation. Second, the utility will likely collect standby revenues from the DG customer (if the standby service is offered at reasonable rates), and these should also be netted out from this calculation. The only situation in which non-DG customers would pay more is if the utility cannot avoid more cost than it loses in revenue. In order to estimate this, we must have both an estimate of the avoided fixed costs, and an estimate of the standby revenues.

[5] I have not used the MECO variable cost from the 1997 rate proceeding, because fuel costs and electric prices have greatly increased since that time. The assumption of $.11/kWh in avoided variable costs is $.10 in fuel ($1.40/gallon / 10,000 BTU heat rate) plus $.01/kWh in variable lube oil and other generation maintenance expenses. This is consistent with the time

Q. How does the utility estimate it's avoidable costs?

A. The utility prepares marginal cost of service studies that show the avoided generation, transmission, and distribution costs. These are filed with the Commission in general rate proceedings. MECO's most recent marginal cost study was prepared in Docket 97-0346, and I discussed this in my direct testimony. The relevant marginal costs, for the purpose of this discussion, are as follows:

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period when MECO posted the average rate for Schedule P of $.1558/kWh.

MECO Avoided Marginal Cost vs. Lost Margin

Cost	$/kw/month	$/year @ 500 kw
Production	$17.60	$105,600
Transmission	$2.70	$16,200
Distribution	$4.79	$28,740
Total Avoided Capacity Costs	$25.09	$150,540
Net **Benefit** to Utility of CHP customer leaving system	$8.37	$50,238

As is evident, the avoided capacity costs from not serving the customer ($150,540) greatly exceed the incremental contribution to fixed costs that the customer would pay if they were served ($100,302). Therefore, we would conclude from this simple analysis of marginal costs versus rates that other customers would pay higher rates if the customer IS served at tariff rates than if they left the system, and lower rates if the customer installs a CHP system. The reason for this is quite simple – MECO's marginal costs exceed it's average costs, and therefore any new load (or retained load of an existing customer) adds more to costs than to revenues.

Q. Did HECO make any estimate of the impact of this in preparing the CHP application?

A. Yes, Exhibit H in the CHP docket contains some calculations, but it does not develop enough CHP to result in multi-year or permanent deferrals of the Waena plant, and it appears that the cost levels used for avoided marginal costs are significantly lower than those now estimated. Both of these assumptions lead to what I believe are faulty conclusions. The issue is quite simple: the marginal cost of new generation greatly exceeds current rate levels, and new generation will result in rate increases. If new generation can be avoided by encouraging customer-owned CHP, rates for non-participant customers will be lower because the higher marginal costs of new resources will be avoided.

Q. This example you have calculated in your Exhibit COM-R-202 and summarized above is based upon MECO's last marginal cost study, prepared in 1997. What would be the result of substituting the much higher costs of capacity submitted by MECO in this proceeding for those used in the 1997 study?

A. The marginal generation capacity costs would be about 35% higher, and the net benefit of the customer leaving the system would be correspondingly higher.

Q. What about the recovery of fixed costs in the form of standby service charges. Would this also help to offset the lost margins due to customer distributed generation?

A. Yes, it would. As detailed below, standby rates should be designed to recover the full cost of providing standby service, taking into account the fact that customer diversity among standby loads means that one unit of standby generating capacity can serve more than one customer's standby demand. If conservatively designed, standby rates can be attractive to the customer, and more than compensatory to the utility.

Q. Have you included standby revenues in your calculation above?

A. No, I have not. Under the standby rate design I have proposed, the utility would receive an additional $1,000 to $2,000 in standby charges per month from this hypothetical customer, further increasing the system benefit of the customer self-generating. Alternatively, one could look at the standby revenue as offsetting any incremental transmission and distribution cost associated with providing standby service, as discussed below in the design of standby rates.

Marginal vs. Embedded Costs and Standby Rates

Q. What are the key issues in this docket relating to the development of standby rates?

A. The key issues are: first, to set rates that are fair to both the Company and to DG owners, so that the Company is fairly compensated for service, and second, to ensure that DG owners do not pay "full-time" for capacity that they need only sporadically and can share with other customers.

Q. How have the parties responded to this need?

A. HECO has provided little guidance. In most of its testimony, HECO recognizes that marginal costs can be avoided, and describes the benefits of doing so. On the other hand, Ms. Seese's testimony measures all types of 'equity" against embedded costs, but provides no guidance at all about the "efficiency" of the Company's current or future rates measured against marginal costs.

Q. In its testimony, the CA advocates that if rates were "unbundled" then the issues surrounding CHP would disappear. Do you agree?

A. No, and for two very different reasons.

First and foremost, MECO's current rates are based on embedded (historical) costs, while the costs it can avoid in the future are marginal (incremental) costs. On a growing system like MECO's, only marginal costs are relevant when looking forward and trying to avoid future costs through encouragement of DG.

Second, there are "good ways" and "bad ways" to unbundle rates, and it is not at all clear what form of unbundling the CA is advocating.

Q. Please begin by discussing the marginal cost issue. Why is it inappropriate to set an unbundled rate design considering only embedded costs, as advocated by the CA and HECO?

A. As I discussed in my direct testimony, the average cost of MECO's existing generating plants is only $687/kw, while the incremental cost of new generating capacity is $3,000/kw. [Page 65, COM T-2] To unbundle the current rates, that are based on $687/kw of investment in production plant, would not send a meaningful price signal to a customer about the costs that would be incurred by MECO were that customer to increase load, or avoided by MECO if that customer were to decrease load. Only marginal costs provide that information.

Q. What has the position of HECO been on these issues?

A. HECO has been inconsistent. In the Ishikawa testimony T-4, at page 18, HECO correctly states:

> "...avoided costs are the incremental or additional costs to the utility of electric energy or firm capacity or both which costs the utility would avoid as a result of the installation of distributed generation. "

In the Sakuda testimony, T-3, at page 5, HECO correctly states:

> "Avoided generation capital costs are those capital costs associated with the installation of firm utility central station generating capacity that can be avoided

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> by deferring the installation date of that firm capacity. Firm DG capacity added to the system can defer the need for new firm utility central station generating capacity and can result in avoided generation capital costs."

These are examples of correct statements of marginal cost measurement, and the applicability of that measurement to the issues in this docket. DG can avoid the need for new generating capacity, and it is the cost of NEW capacity that is relevant.

Q. What is the conflicting evidence submitted by HECO?

A. In the Seese testimony, T-5, and in response to COM information requests, HECO has asserted that embedded (historical) costs are what is relevant:

> "Any loss of embedded fixed cost-rlated revenues due to customer self generation, regardless of whether such lost fixed cost-related revenues are lower or higher than marginal costs, will be shifted to other ratepayers."[6]

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The appears to reflect a fundamental misunderstanding on the part of this HECO witness of what drives utility rate increases. If HECO can avoid the need for new power plants through DG (or DSM), it will avoid the need to raise rates. If it cannot avoid the need for new power plants, then the marginal costs of those new power plants will become the drivers for the next rate case – and <u>all</u> customers will face higher rates.

Q. Has Ms. Seese been consistent in her misunderstanding of the role of marginal costs?

A. No. In her testimony on uneconomic bypass, she states:

> "Uneconomic bypass occurs when the cost of a customer's alternative source of electrical energy is lower than the cost of receiving service under HELCO's

[6] Response to COM-SIR-5

> applicable standard rate schedule, but higher than HELCO's **marginal** cost of providing service."

This is a correct statement. Since the utility's marginal costs exceed its average costs, avoiding load growth (or securing load reduction) is almost always an economic form of bypass, providing cost benefits to all customers. If the cost of new power plants were lower than the cost of existing units, this situation would be different, but as long as MECO is in a position to avoid a $3,000/kw power plant, and serve load with power plants costing less than a third of this amount, uneconomic bypass is not a real concern for MECO.

Q. Does DG create a risk of uneconomic bypass for the MECO system?

A. No, it does not. The MECO system is growing, with six new power plants scheduled for construction over the next decade. DG can defer or eliminate the need for some or all of these new power plants. Since these new units have marginal costs that greatly exceed system current average costs, deferring or avoiding them will prevent rate increases for existing customers. Therefore, it is reasonable to conclude that bypass is likely to be economic on the MECO system.

Q. Under what conditions would DG potentially lead to higher rates for existing customers?

A. The only circumstance under which the loss of utility load to DG would result in a shift of existing fixed costs onto remaining customers would be if MECO had a shrinking sales base and therefore DG development resulted in excess capacity. This is unlikely to occur, since each of the major systems (HECO, HELCO, and MECO) are growing, and the costs that can be avoided through DG exceed the embedded costs in rates. Further, in order for such a cost shift to occur, the Commission would need to find that the cost of the resulting excess capacity was appropriately borne by the remaining customers. There is no certainty that this would be the result of such a proceeding.

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Q. Are there examples of proceedings in which regulatory commission have disallowed the cost of new generating facilities when utility loads migrated off the system, through economic or uneconomic bypass?

A. Yes. During the mid-1980's, many Commissions dealt with excess capacity situations caused by utilities building new power plants in advance of load, and simultaneously suffering load losses due to the combination of a weak economy and rising electricity prices. I was involved in several such cases. In Montana, the Commission found the Colstrip #3 coal power plant investment not "used and useful" because the utility did not need the resources to meet its test year loads.[7] In a case I was involved in in Arizona, the Commission ruled that a portion of the investment in the Palo Verde nuclear plant #3 was not needed to service retail customers for several years after the plant entered service, and deferred adding the cost to rate base until it was deemed "used and useful."[8] I recall that the New Mexico Commission denied inclusion of a portion of Palo Verde in rate base, and that Public Service Company of New Mexico has treated that as an unregulated investment since that time. I do not have a copy of the New Mexico Commission's order.

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There have also been cases in the natural gas industry where the availability of "transportation" service (the gas-equivalent of retail wheeling) left utilities with lost margin. In some cases, the utility's ability to recover that lost margin was deferred for several years, until after a general rate proceeding, so there was no "dollar-for-dollar" recovery of the losses.

Q. Is there evidence produced by HECO that there are not likely to be stranded costs on the MECO system if there is rapid development of DG?

A. Yes. I have included both the Company's estimate of potential CHP capacity, from Exhibit A, and the Company's estimate of future generation addition needs, from Exhibit H in

[7] Montana Department of Public Service Regulation, Order No. 5051c

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the CHP proceeding in my exhibit. These clearly show that the addition of DG to the MECO system will defer the need for and cost of expensive new generating facilities. Since MECO can defer generation additions, there is no reason it should experience any stranded costs as a result of customer-installed self-generation.

Q. Please summarize your discussion of marginal costs and how they apply in this proceeding?

A. I agree with the HECO testimony of Sakuda and Ishikawa, that the relevant costs to consider in evaluating the desirability of DG are system marginal costs, including avoidable marginal generation, transmission, and distribution costs. I disagree with the testimony of Ms. Seese and Mr. Herz that any form of rate analysis based on embedded costs should be relied upon to produce efficient results. Looking only in the rear-view mirror is not the safest driving style. We need to look ahead to costs that can be avoided.

Standby Rate Design

Q. How does all of this bear on the appropriate design of standby rates to customers that install DG equipment?

A. Customer that install DG equipment are helping the utility to avoid marginal costs. To the extent that marginal costs exceed embedded costs, the issues of lost margin and adverse impacts on non-participating consumers are resolved in favor of encouraging DG. This is unambiguously the situation for MECO, where DG can help avoid \$3,000/kw generating facilities, and embedded costs reflect only \$687/kw for generating facilities.

This leaves the issue of design of standby rates that are compensatory to the utility, and fair to

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[8] Arizona Corporation Commission, Order No. 57649

the customer. The testimony of HECO and the CA provides little guidance on how to do this. HECO's rate design testimony focuses on embedded costs, which are relevant but not controlling, while the CA testimony discusses unbundling, without defining what it means or how to do it.

Q. Have other states established standby rates that are fair and reasonable to both the utilities and to customers?

A. Yes. California and New York have both adopted fully unbundled rate designs, and in so doing, adopted very sensible and reasonable standby rates for DG customers. Conversely, it would be possible to develop a standby rate that was inappropriate and unfair, but still in the guise of "unbundling." In order for the term "unbundling" to be meaningful, it must be defined, be examined, and be reasonable.

Q. How do you define an "unbundled" rate as it would apply to standby service?

A. An unbundled rate for standby service would separate out the customer-specific costs of connecting a specific customer to the utility grid from the costs of joint production and transmission facilities that are used by multiple customers. The customer would pay a fixed annual fee for the connection to the system, what is called a 'capacity reservation' payment, and a variable amount for actual standby service depending on how much and how often they actually require standby service. In this manner, a customer that used standby service very little (and therefore did not cause the utility to invest in facilities to provide standby service) would pay much less than one who relied on the utility frequently. It would provide an incentive for customers to install reliable equipment, and to maintain that equipment, while ensuring that customer using standby service frequently fully compensate the utility for providing firm year-round service.

Q. What type of rate would be least appropriate for standby service?

A. A rate that bundled the full annual costs of standby service for hundreds of days per year into a fixed fee that applies regardless of the frequency of standby usage would be an inappropriate standby rate design. A customer that uses standby service frequently should pay a much higher cost than one who seldom requires service, simply because the latter customer can "share" standby facilities with many more customers, and should be allowed to share the cost of those facilities with the other customers that use the standby facilities.

Q. What, in your judgment, is the best way to set standby rates for DG customers?

A. The rates should be set so that each DG customer contributes a portion of the cost of owning and maintaining the capacity that collectively provides service to all DG customers in proportion to how much and how often the individual customers use that standby capacity. Because HECO estimates that there will be many DG customers (with or without HECO involvement, and because DG systems are not all expected to be out of service simultaneously, it is only necessary for the utility to have a fraction of the combined DG capacity installed on its system in reserve in order to meet the standby needs of these customers.

Q. How do you estimate the amount of standby capacity the utility requires in order to provide standby service to DG customers?

A. One does this the same way one estimates the capacity needed to serve firm customers. First, one looks at the combined individual loads of the individual customers on the system. Second, one looks at the probability, or "coincidence" that these loads will occur at the same time. Finally, one measures this coincidence of loads against the other loads on the system to determine if additional capacity is necessary. Simply stated, if CHP systems are expected to operate 85% of the time, then the utility needs to have only 15% of the CHP capacity available in order to provide standby service; for example, if 50 1-MW systems are installed and have an average availability of 85%, the utility would need only about 7.5 MW of standby capacity in order to provide standby service without putting any pressure on firm customers even if there were no coordination of maintenance schedules. Under these circumstances, each standby customer should be expected to pay about 15% of the cost of a standby generator.

With coordination of maintenance into lower-demand months, the required standby capacity would be even lower.

Q. Are there steps the utility and Commission can take to reduce the cost of providing adequate standby capacity?

Yes. DG systems require annual maintenance, which can be scheduled, and also have forced outages, which can occur at any time. In the case of DG, the need for standby capacity can be controlled a bit, by requiring (as a condition of standby service) that the customers coordinate their annual maintenance outages and other scheduled outages in conjunction with the utility. This can assure that systems will not be taken out of service during the peak periods of the year – historically mid-summer, and Christmas break on the MECO system. While there is still the risk of forced outages, this risk is very small (typically less than 5% for modern CHP systems), and the utility needs only to have about 5% of the capacity of CHP customers available during peak periods to provide standby service. If this is done, the generation standby rate needs only to recover about 5% of the cost of a standby generator from <u>each</u> DG customer.

Q. Do some DG systems have higher reliability than others?

A. Yes. There are several types of DG systems, and several manufacturers. Each may have slightly different annual maintenance requirements, and slightly different forced outage rates. This can range from microturbine and IC engine systems with 90%+ reliability down to wind turbines and solar systems which may have much higher reliability (99%+) but much lower availability factors (30% - 50%).

Q. How can standby rates be designed to recover a fair amount of revenue from each type of DG installation?

A. The New York Commission has developed a very sensible approach to standby pricing that makes each standby customer pay a fair amount for the capacity they use from the utility. There are three parts to the standby rate:

> **Capacity Reservation Charge:** A $/kw/year charge that covers the cost of being connected to the utility, including net transmission and distribution capacity costs, that are customer-specific. This can include ancillary services that the utility provides at all times, such as spinning reserves. This should reflect the expectation that DG systems will bring transmission and distribution system benefits. It should be higher for customers served at secondary voltage than those served at higher voltages.

> **As-Used Daily Standby Demand Charge:** A $/kw/day charge that covers the cost of the generating capacity that the customer actually uses. A customer using standby service 100 days per year pays five times as much under this approach as one using standby service only 20 days per yea. Each standby customer therefore bears the cost of standby capacity in proportion to how often they use it. This should be lower on days of the week and months of the year when demand is lower and the utility does not need to reserve any otherwise-unneeded capacity to serve the diversified needs of standby customers.

> **Standby Energy Charge:** A $/kWh charge that recovers the variable cost of the energy used by the standby customer. In New York, this is a real-time energy charge, based on power pool dispatch conditions. In Hawaii it would most logically be a time-of-use energy charge, adjusted monthly for fuel costs.

Q. Does this type of rate design address the concerns raised by the other parties in this proceeding?

A. Yes, I believe it does. This is an unbundled rate design, as recommend by Mr. Herz.[T-1, P. 66]. It assures that the utility is fully compensated for both the capacity and energy used by standby customers, as recommended by HECO [T-5, P. 17]. It provides a predictable and reasonable rate for standby service that can be applied on a non-discriminatory basis, as recommended by HESS [Gregg, P. 3]. It does not "zero out" the standby charge as recommended by HREA [Bollmeier, table on final page], but it would greatly reduce the standby charge for customers with reliable systems compared, for example, with the extremely high (and, I believe, punitive) HELCO standby charge.

Q. How would you recommend calculating each of the elements for this standby rate?

A. Initially, I would recommend that the Standby Reservation Charge be set at one-half of the transmission and distribution charges in tariff rates. This recognizes the position of all parties that DG can provide transmission and distribution system benefits to the system. I recommend that all remaining fixed costs be recovered in the as-used standby demand charge. Variable costs would be recovered in the standby energy charge.

Q. In the longer-run, how should standby T&D costs be estimated?

A. I believe it would be appropriate to require the utilities to prepare IRP studies on the transmission and distribution system expansion requirements with and without DG systems in place for each circuit where capacity upgrades are anticipated within ten years absent DG investment. For those circuits, the avoided T&D costs can be estimated from the cost savings due to investment deferral. The standby rate should be based on the normal tariff rate (i.e., what the customer would pay if it were a full-requirements customer), minus the avoided cost for the utility from the DG installation (i.e., what the utility would avoid by the customer NOT being a full-requirements customer).

I would expect this to produce costs higher than the 50% benchmark I have proposed in some cases, and lower in others.

Q. Until there is extensive experience with multiple DG systems taking standby service, how would you design the As-Used Standby Demand Charge?

A. I would first subtract the standby Reservation Charge from the demand-related costs derived from the utility's cost of service study, to produce a net amount to be recovered through this as-used standby demand charge. I would then divide this by 200 days per year to produce a daily as-used standby demand charge. This rate would apply Monday through Friday; on weekend, one-half of the resulting rate would apply.

This would recognize that there is a significant probability that the forced outages of standby units would not be evenly distributed throughout the year, that on some days the utility would serve one outage in the morning and another in the evening, and charge for both, and that the utility would statistically have to have slightly more capacity available than a simple calculation based on the forced outage rates of the units to provide a high probability of being able to serve all standby demands.

I would apply one-half of the normal standby rate for service provided on Saturday and Sunday. This would provide owners of DG equipment an incentive to perform routine short-duration maintenance (such as oil changes on internal combustion engines) on the weekend, when system demands are typically lower even during the peak season.

As-Used Sat-Sun Standby Demand Charge		$/kw/day	$0.49
Standby Energy Charge (Computed monthly based or current fuel and other variable energy costs)		$/kWh	Monthl, Variable Energy Costs

Q. Have you computed a sample standby rate using these principles for the MECO system?

A. Yes. This is developed in my exhibit COM-R-203, based on the last cost study MECO prepared, and the results shown below:

Q. You have computed these based on the embedded cost analysis prepared by MECO in its last rate case. You have previously testified that marginal costs should be the basis of efficient rate design. Please explain why you have used embedded costs?

A. Marginal costs are the correct measure of efficiency, but not necessarily the best measure of equity. In determining whether DG is "good" or "bad" for existing customers, it is appropriate to compare marginal costs to the revenues that would be foregone if customers choose DG. Under current Hawaii ratemaking practices, however, if the customer chooses tariff service, they would pay rates based on embedded costs. I have computed these standby rates using the same principles, so that there would not be discrimination. This is an *equity* consideration, not an *efficiency* consideration. Under this approach, customers would be encouraged to choose DG if it is efficient for them to do so, and would pay non-discriminatory and equitable rates to the utility for service provided once that decision is made.

Q. If the Commission adopts your proposal for a generation impact fee, based on marginal generation costs, would your recommendation change?

A. If generation impact fees were assessed (on a probability-weighted basis) on standby customers, they would have paid the difference between marginal costs of standby service and embedded costs in a one-time fee, and would be entitled to embedded-cost based standby rates as I have calculated above. If generation impact fees were imposed, as I recommend, on utility sales customers, but <u>not</u> on DG customers, then it would be appropriate to compute the standby rates using marginal costs. The standby reservation charge and standby as-used demand charge would be somewhat higher reflecting the fact that MECO's marginal costs exceed its embedded costs. My Exhibit COM-403 shows the derivation of this, but I note that the marginal costs used are out-of-date from 1997, and should be updated to reflect the $3,000/kw cost of the newest proposed power plants.

Q. In your direct testimony, you also proposed a "best efforts" standby rate, in which the utility would not be obligated to provide standby service if doing so caused its reserve margin to drop to unacceptable levels. How would this approach work in the context of the rate design formula you have proposed above?

A. A customer taking best-efforts standby service is not creating <u>any</u> requirement for the utility to invest in any generation or transmission plant or equipment to provide standby service. Arguably, there is no basis for the as-utilized daily standby demand charge at all. However, it is a precept of regulation that any customer using system capacity, at any hour,

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should help pay for the cost of that capacity.[9] Therefore I recommend that at least a nominal as-utilized demand charge should apply to best-efforts standby service. I propose that one-third of the normal standby demand charge (both standby reservation charge and as-used daily standby demand charge) apply to best-efforts customers.

Q. What behavior would you expect this approach to evoke?

A. I would expect customers with non-critical loads to choose best-efforts service up to the level of those loads. This could be industrial customers with process energy requirements, or resort hotels that can interrupt service to their water features, laundry, and other non-critical loads. If the customer's DG unit failed during a time when the utility was not under stress, it would then place that load on the utility if the utility had sufficient capacity, and contribute financially to the cost of that capacity. If the utility was under stress at that particular hour or day, the load would go unserved until the utility's reserve margin recovered. Since the probability of the failure of the customer's DG system at the same time the utility system is under stress is quite low, this might be a reasonable gamble for some customers. To the extent they choose this option, it would provide a contribution to the utility's fixed costs without actually imposing any corresponding cost on the utility. The utility's other customers would be made better off by the receipt of this revenue.

Time Of Use Rate Design

Q. What has the Company testified with respect to time-of-use rates?

[9] See, e.g., Garfield and Lovejoy, Public Utility Economics, 1964, P. 163, quoting Dr. Henry Herz, NARUC Cost Allocation Committee: *"All utility customers should contribute to capacity costs; The longer the period of time that a particular service pre-empts the use of capacity, the greater should be the amount of capacity costs allocated to that service; Service that can be restricted by the utility should be allocated less in demand cost as the degree of restriction increases."*

A. Ms. Seese testified that the current load-factor blocks in the Company's Schedule J and P are de-facto time of use rates.

Q. Do you agree with this assessment?

A. No I do not. The current rate design provides an incentive for customers to maximize their individual load factors, that is, to use power steadily 24 hours per day, 365 days per year. A time-of-use rate would encourage customers to use power sparingly during the priority peak hours of the day. The HECO/MECO/HELCO rate designs do not do this.

Q. Provide an example of how the current rate designs encourage uneconomic behavior.

A. Assume a hypothetical customer that has as their primary electricity use a night-time activity, such as security lighting for an automobile dealership. The customer is using power about 12 hours per day, but very little during the priority-peak hours of the afternoon from 1 - 6 P.M. when the utility experiences it's peak demand. With 360 hours per month of usage, the customer would fully consume the first block, and nearly fully consume the second block. Looking at the utility's rate schedule, this hypothetical customer would see that incremental usage – another 100 to 300 hours of usage per month – would be <u>much</u> cheaper than the current level of usage. In the situation this customer is in, however, the only hours remaining when they could consume power would be daytime hours – right when the utility experiences its peak demand. Any increase above 400 kwh/kw for this customer would <u>increase</u> the utility's peak demand.

Q. Is there an alternative that would promote greater efficiency for these systems?

First 200 kWh/kw		$0.12
Next 200 kWh/kw		$0.10
Over 400 kWh/kw		$0.08
Alternative TOU Design		
Demand Charge:		$5/kw
Priority Peak		$0.15
Shoulder Peak		$0.12
Off-Peak		$0.08

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A. Yes. The utility's current load factor blocks could be converted to time-of-use blocks. Ideally, the rate would be designed to produce the same revenue as the current rate design, but with all generation capacity costs reflected primarily in the on-peak and shoulder-peak energy blocks.[10] The demand charge would recover only transmission and distribution capacity costs. I have not fully designed such a rate, but have set out an example of what the final product would look like.

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The table below, developed in Exhibit COM-R-204, shows the type of change to the rates that is appropriate:

[10] It is a well-understood principle of ratemaking that all customers that use capacity should contribute something towards that capacity, so even the off-peak rate should include some contribution to generation capacity costs; this avoids pure "hitchhikers" that use resources paid for by others.

Q. Are there reasons why time-of-use rates were not appropriate in the past, but are appropriate today?

A. Yes. In the distant past, when fuel costs were much lower, the utility may not have had such time-differentiated costs. Today each of the utilities plans to use high-efficiency combined-cycle power plants to meet baseload needs, and peaking units with much higher fuel costs during priority peak periods. To fail to recognize this in rates results in the potential for wasted oil. At current prices (as this is being written) of $50+/barrel, this is inexcusable.

Second, in the past, the cost of time-of-use metering may have been prohibitive. Today, the incremental cost of a TOU meter for the size of customers on Schedule P is trivial compared to the cost savings that might be achieved. The Commission should direct the immediate development of TOU rates for Schedule P (where the incremental metering costs for the relatively few customers not already having TOU capability are trivial), and evaluation and possible phased development for Schedule J (so that existing meters, as they wear out or become obsolete are replaced with TOU-capable meters).

Finally, in the past the cost of energy management systems for office buildings, hotels, and other large customers were quite high. As a result, their ability to respond to TOU prices were more limited. Today, energy management systems are a standard feature of new buildings, and a cost-effective retrofit investment for many existing buildings. Providing TOU pricing reflecting the utility's time-variant costs will provide an incentive for customers to use their energy management systems to save money for themselves and for the utilities.

Q. Do you routinely recommend TOU rates?

A. No. Much of my work is done in the Pacific Northwest, where hydro capacity provides most of the peaking power. The TOU cost differentials can be much smaller, and the cost-effectiveness of TOU metering can be lower. I have found that TOU pricing is NOT cost-effective for residential customers, and I am not recommending consideration of residential TOU pricing in Hawaii at this time. However, for large customers (such as those on Schedule P), I nearly always find that TOU metering and pricing is cost-effective.

Q. How does this concept relate to the issues in this proceeding, the encouragement of distributed generation?

A. It relates in two different ways. First, with time-of-use rate design, the utility will be encouraging customers to choose DG system when the savings from those systems is cost-effective. Under the current rate design, the utility may be providing inefficient signals to customers, causing uneconomic investment (or lack of investment).

Second, and perhaps more important, if the utility established time-of-use rates for Schedules J and P, it could then easily implement time-of-use standby rates. These would provide the strongest possible incentive for DG customers to make sure their equipment is operating during on-peak periods. With the current rate design, the customer would have an incentive to take their equipment down for a continuous period -- day and night -- for maintenance. With a TOU rate, the customer would have an incentive to do maintenance during night-time hours spread over a longer period of time, keeping the equipment operating during peak periods when the output is most valuable and does the most to ensure reliable service to other customers.

Summary

Q. Please summarize your rebuttal evidence.

A. First, I have testified to the market power issues that surround the proposal by the Company and the CA to allow the utility to enter the DG marketplace. I have demonstrated that this would lead to a highly concentrated market, in which the benefits of competition could not be expected to materialize.

Second, I have demonstrated that the lost revenue issues raised by the Company and by the CA are smokescreens, inapplicable to the current situation that MECO is in, with avoidable new power plants that cost more than three times as much as existing power plants. Any avoided load defers the needs for this expensive new generation, and will result in lower rates for other customers.

Third, I have developed a specific methodology for the development of unbundled standby rates that meet the goals of both the Company and the CA. These include a standby capacity reservation charge equal to one-half of the fixed costs of transmission and distribution, plus an as-used standby capacity charge, imposed on a daily basis, for actual use of standby service. I have demonstrated that this will result in reasonable costs for standby customers, and more than fully compensate the utility for any incremental facilities that are needed to preserve reliable service in the face of increasing DG use and increasing demands for standby service. I have also demonstrated a way to use these same principles to offer best-efforts standby service that is also fair to customers and also more than fully compensates the utility for the cost of service.

Finally, I have demonstrated that the Company's current load-factor block rate design is inefficient, and encourages uneconomic behavior. I have proposed an alternative time-of-use rate design that would encourage efficiency, and serve as the basis for time-of-use standby rates that would encourage optimal management strategies by DG owners.

This completes my rebuttal evidence.

Example of Lost Revenues and Costs

Revenues

500 kw @ 50% load factor =	2,190,000	kwh/year
Average Rate:	0.1558	MECO website
Annual Revenue:	$341,202	
Variable cost/kwh	$0.11	Assumed
Fixed Cost/kwh	$0.0458	Calculated
Fixed Cost Recovery / Year:	$100,302	Calculated
Fixed Cost Recovery/kw/year	$200.60	Calculated
Variable Cost Recover / Year	$240,900	

Standby Charges

Reservation fee = $/year/kw	$25.00
Daily M-F As-Used Demand Charge = Annual Fixed Cost / 200	$1.00
Sat-Sun As-Used Demand Charge @ 50% of M-F Price	$0.50
Variable Rate = Variable Cost = $1.40/gallon / 10,000 btu heat rate + $.01/kWh	$0.11

Assumptions:
50 days standby/year; 30 days M-F at Full Price; 20 S/Su at 50% of Full Price
90% load factor on standby days (assumes CHP runs baseload)
kwh/year

Standby Revenues:

Reservation fee:	$12,500
As-Used Demand Charge:	$20,060
Total Contribution to Fixed Costs:	$32,560
Assume 5 Standby Customers Sharing Standby Capacity	$162,802
Gained Net Margin For Utility:	**$62,500**
Assume 10 Standby Customers Sharing Standby Capacity	$325,604
Gained Net Margin for Utility	**$225,302**

Substitute Estimated Current Costs for Former Estimates of Capacity Cost
Derived from MECO Marginal Cost Study

	1997	Current Costs
Monthly Cost/kw	$18	$23
Annual cost/kw	$211	$282
Annual real carrying charge rate	0.0939	0.0939
Capital Cost / kw	$2,249	$3,000

Ratio:	133.38%

HHI Estimates

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HECO

		%	
Total Systems	97		
HECO-Owned	72	74.23%	
Other Owned	25	25.77%	0.0103093
HECO contribution HHI		5,510	
If all others sold by 1 firm:		664	
If all others sold by 1 firm per system:		27	
Minimum HHI:			5,536
Maximum HHI			6,174
Conclusion:		**Highly Concentrated**	

HELCO

		%	
Total Systems	92		
HECO-Owned	68	73.91%	
Other Owned	24	26.09%	0.0108696
HECO contribution HHI		5,463	
If all others sold by 1 firm:		681	
If all others sold by 1 firm per system:		28	
Minimum HHI:			5,491
Maximum HHI			6,144
Conclusion:		**Highly Concentrated**	

MECO

		%	
Total Systems	99		
HECO-Owned	76	76.77%	
Other Owned	23	23.23%	0.010101
HECO contribution HHI		5,893	
If all others sold by 1 firm:		540	
If all others sold by 1 firm per system:		23	
Minimum HHI:			5,917
Maximum HHI			6,433

Conclusion: **Highly Concentrated**

Source of data: HECO Exhibit A to CHP Filing

MECO Standby Rates from COS Study

System Costs Per COS in 97-0346

Embedded Costs	**Monthly**	**Annual**
Demand		
Production	$13.66	$163.92
Transmission	$3.01	$36.12
Distribution	$2.47	$29.64
Total Demand Costs	$19.14	$229.68
Energy Cents/kWh		
Priority Peak	n/a	
Shoulder Peak	n/a	
Off-Peak	n/a	
Total Energy Costs	5.57	5.57

Note: Fuel costs and energy costs have risen dramatically, and these do NOT represent a reasonable estimate of current energy costs; variable standby charges should reflect current variable costs.

Step 1: Set Standby Capacity Reservation Charge = 50% of T&D Cost

Total T&D:	$5.48	$65.76
50% of T&D:	$2.74	$32.88

Step 2: Set Standby As-Used Demand Charge Based on Residual Demand Costs

Total Demand Costs:	$229.68
Less Standby Reservation Charge:	($32.88)
Residual Demand Costs	$196.80
Divide by 200 days of standby service/year	200
As-Used Daily M-F Standby Demand Charge	$0.98

Standby Rate Derived From MECO Cost Study

Standby Reservation Charge: (50% of T&D cost)	$/kw/year	$32.88
As-Used Daily M-F Standby Demand Charge (100% of Remaining Fixed Costs / 200 Days/year)	$/kw/day	$0.98
As-Used Sat-Sun Standby Demand Charge	$/kw/day	$0.49
Standby Energy Charge (Computed monthly based on current fuel and other variable energy costs)	$/kWh	Monthly Variable Energy Costs

Marginal Cost Based Standby Charge	**Monthly**	**Annual**
Demand		
Production	$17.60	$211.20
Transmission	$2.70	$32.40
Distribution	$4.79	$57.48
Total Demand Costs	$25.09	$301.08
Energy Cents/kWh		
Priority Peak	5.43	
Shoulder Peak	5.29	
Off-Peak	4.93	
Total Energy Costs	5.16	5.16

Note: Fuel costs and energy costs have risen dramatically, and these do NOT represent a reasonable estimate of current energy costs; variable standby charges should reflect current variable costs.

Step 1: Set Standby Capacity Reservation Charge = 50% of T&D Cost

Total T&D:	$7.49	$89.88
50% of T&D:	$3.75	$44.94

Step 2: Set Standby As-Used Demand Charge Based on Residual Demand Costs

Total Demand Costs:	$301.08
Less Standby Reservation Charge:	($44.94)
Residual Demand Costs	$256.14
Divide by 200 days of standby service/year	200
Monday-Friday Standby Demand Charge	$1.28

dby Rate Derived From MECO Marginal Cost Study

Standby Reservation Charge: (50% of T&D cost)	$/kw/year	$44.94
Monday-Friday Standby Demand Charge (100% of Remaining Fixed Costs / 200 Days/year)	$/kw/day	$1.28
Saturday-Sunday Standby Demand Charge	$/kw/day	$0.64
Standby Energy Charge (Computed monthly based on current fuel and other variable energy costs)	$/kWh	Monthly Variable Energy Costs

TOU Rates In Place Of Load Factor Blocks

Current Rate Design

Demand Charge:	$10/kw
First 200 kWh/kw	$0.12
Next 200 kWh/kw	$0.10
Over 400 kWh/kw	$0.08

Alternative TOU Design

Demand Charge:	$5/kw
Priority Peak	$0.15
Shoulder Peak	$0.12
Off-Peak	$0.08

Elements:

1) Demand charge recovers only T&D costs
2) Generation capacity costs recovered primarily in on-peak and shoulder peak energy charges.
3) Off-peak energy charge includes some generation capacity costs (as it does under present rates).

Rates are illustrative; actual rate design would require system costs and system billing determinants.